BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion into the Rates, Operations, Practices, Services and Facilities of Southern California Edison Company and San Diego Gas and Electric Company Associated with the San Onofre Nuclear Generating Station Units 2 and 3.	Investigation 12-10-013 (Filed Oct. 25, 2012)
And Related Matters.	Application 13-01-016 Application 13-03-005 Application 13-03-013 Application 13-03-014

THE COALITION TO DECOMMISSION SAN ONOFRE'S OPENING COMMENT ON JOINT MOTION OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), ET AL FOR ADOPTION OF SETTLEMENT AGREEMENT

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Table of Contents

Authorities and References

Commission Decisions

Advice Letters

Data Requests & Responses

Other Documents

I. INTRODUCTION

A settlement has been proposed for the California Public Utilities Commission (CPUC) investigation into the outage at the San Onofre Nuclear Generating Station (SONGS). We believe this settlement is not in the best interests of the public, for a number of reasons that will be fully explained below. In a nutshell, we find that the settlement 1) does not include all the issues that were explicitly listed as issues in the investigation, 2) weighted heavily in favor of the utilities, despite imprudent management of the Steam Generator Replacement Project (SGRP), (which is the presumption absent a desire by the utility to show otherwise) 3) heavily reliant on future events, thereby not actually "settling" those issues, 4) costly and difficult to monitor and maintain the agreement over many years or decades, which is probably great for the attorneys that are involved but not at all in the best interests of the public or the Commission, 5) does not include incentives for the utility to perform future actions quickly and for the benefit of the ratepayer.

We see this a good first step in the process, and we recommend that the Commission: 1) deny approval of this settlement proposal, 2) define requirements of any settlement agreement that will be acceptable, and 3) define a settlement negotiations process that include all parties that desire to be included and probably a magistrate that can assist in the process. (The Coalition to Decommission San Onofre (CDSO) has previously objected to the negotiation process. Since there was no explicit response to this objection, we will repeat that material in this document as it continues to be relevant.)

There are almost no disadvantages to the Commission and the public to denying this first settlement proposal and going through a more careful process which is structured by the Commission according to a set of requirements, and there are many advantages, particularly when the overall cost of the settlement is evaluated, in terms of how much Commission overhead it requires over the next many years and decades, versus a settlement agreement that actually settles the issues and firmly puts them to bed, at least in terms of the needed work by the Commission, and those of us that are attempting to provide oversight of the entire process.

Although the utilities have adopted the position that the settlement agreement must be adopted with no changes whatsoever, we believe this is just posturing, and the Commission should simply deny the approval of this proposed settlement agreement, structure the requirements of any settlement, and turn it back for further negotiation within those constraints. As it stands, the agreement is tailored to maximize the revenue of the practicing attorneys while requiring almost unending monitoring by the Commission. The resulting settlement, we believe, should be much simpler and therefore easier to understand and monitor.

Nuclear energy is extremely dangerous and requires compliance with safety regulations of the Nuclear Regulatory commission (NRC). SCE, in their application to replace the steam generators, asserts that they could complete the project safely and economically, and that the new steam generators would probably last another 40 years. Instead, the steam generators were only operational for an extremely minor fraction of the estimated operational lifetime. Unit 2 was only operational for about 18 months, or 3.75% of the projected operational lifetime. Unit 3 was only operational for 11 months, or 2.3% of the projected operational lifetime. (Unit 2 was undergoing routine fuel rod replacement in January 2012, so was not generating electricity when vibration caused Unit 3 shutdown, but the routine maintenance being undertaken at the time was a planned outage, and therefore is counted toward the operational lifetime for that Unit.) Furthermore, the entire plant had to be shuttered as a result.

This design failure was one of the most serious engineering and management blunders ever facing Southern California. Fortunately, no one died and the region did not need to be evacuated on a permanent basis. Now, the settlement proposes that ratepayers pick up the tab for about $3.3 billion while SCE management is rewarded with millions in profits from stock liquidations, and investors largely emerge unscathed. The settlement process is imprudent, unreasonable, and unfair to ratepayers.

The Coalition to Decommission San Onofre (CDSO) objects to the motion to adopt the settlement, and opposes the settlement. The rationale for our position is presented below.

About CDSO

CDSO is a project of Citizens Oversight, Inc. a 501c3 nonprofit organization with offices in the San Diego County area, and which represents a number of residents and organizations in the vicinity of the San Onofre Nuclear Generating Station (SONGS). Included in this group is Residents Organized for a Safe Environment (ROSE), San Clemente Green, San Onofre Safety. Members include ratepaying residents in both the SCE and SDG&E areas of service, as well is many who live in the nuclear danger zone of the plant.

II. BACKGROUND

Key milestones in this case are as follows:

1. On 15 December 2005, the CPUC issued Decision D.05-12-040[1] granting SCE a rate increase for the Steam Generator Replacement Project (SGRP) at San Onofre as requested in A.04-02-026. In Decision D.05-12-040 the CPUC:

   1.1. Order #3: The reasonable cost estimate for SGRP cost is $680,000,000 ($569,000,000 for replacement steam generator installation and $111,000,000 for removal and disposal of the original steam generators)[2].

   1.2. Order #5: If the SGRP cost exceeds $680 million, or the Commission later finds that it has reason to believe the costs may be unreasonable regardless of the amount, the entire SGRP cost shall be subject to a reasonableness review[3].

2. Order #11: After completion of the SGRP, SCE shall be required to file an application for inclusion of the SGRP costs permanently in rates, regardless of whether costs exceed $680 million. If a reasonableness review of such costs is performed, it shall be done in connection with the application. In the event the removal and disposal of the original steam generators is delayed significantly beyond the commercial operation of both units, it may be addressed in a subsequent application[4].

   "SCE proposes to file an application to establish the reasonableness of the SGRP construction costs, excluding the costs of removal and disposal of the original steam generators, six months after SONGS returns to commercial operations.[5]" Thus, although SCE was required to file an application with the Commission for inclusion of SGRP costs in rates, and SCE proposed doing it within six months after the start of operations, no such application was filed.

3. A number of Advice Letters were filed with the PUC in subsequent years describing revenue requirements related to the steam generator replacement project, summarized below, along with key milestone dates in the project and proceeding. Many of these Advice Letters refer to the Original Steam Generators (OSGs) which had to be removed and disposed as they are radioactive.

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1 D.05-12-040 - Final Decision on SONGS SGRP, 2005-12-15 (http://www.copswiki.org/Common/M1422)
2 D.05-12-040 Page 108, Order #3
3 D.05-12-040 Page 109, Order #5
4 D.05-12-040 Page 110, Order #11
5 D.05-12-040 Page 48-49.

Date (AL)	Amount $M Nominal USD	Description

2005-12-28 (AL 1951-E)	3.03 (4.04 at 100%)	2006 Revenue Requirement, SCE share (75.05%) , OSG removal and disposal costs.
2006-11-30 (AL 2067-E)	3.32 (4.24 at 100%)	2007 Revenue Requirement, SCE share (78.21%) OSG Removal and disposl costs.
2007-11-30 (AL 2187-E)	3.60 (4.60 at 100%)	2008 Revenue Requirement, SCE share (78.21%) OSG Removal and disposal costs.
2008-11-24 (AL 2292-E)	3.78 (4.83 at 100%)	2009 Revenue Requirement, SCE share (78.21%) OSG Removal and disposal costs.
2009-06-30 (AL 2355-E)		Establishes two balancing accounts for SGRP
2009-11-16 (AL 2402-E)	3.84 (4.91 at 100%)	2010 Revenue Requirement, SCE share (78.21%) OSG Removal and disposal costs.
2011-02-28		2010 SEC 10K reported SG were replaced in 2010-04 (Unit 2) and 2011-02 (Unit 3)
2011-08		Six months after replacement and application for reasonableness review of construction costs. No application was filed.
2011-12-27 (AL 2468E)	115.239	2012 revenue requirement for replacement steam generators.
2012-01-10		Unit 2 entered planned refueling outage, to include inspection of steam generator tube wear.
2012-01-31		Emergency shutdown of Unit 3 after radiation leak to the environment. Subsequent inspections identified cause as tube-to-tube wear due to inadequate computer modeling.
2012-10-25		CPUC issued Order of Investigation (OII) I.12-10-013, including provision for accounts to retroactively account for expenditures in rates for SGRP and SONGS.
2012-12-31 (AL 2834-E)	A. 130.766 B. 17.924 (22.92 at 100%)	A. Modified revenue requirement for 2012 for Replacement Steam Generators. B. 2013 OSG removal and disposal costs.
2013-01-08		I.12-10-013 Prehearing conference, setting out the plan for four distinct phases.
2013-01-28		I.12-10-013 Scoping ruling establishing a number of phases, with Phase 3 to include causes of the steam generator failure and allocation of responsibility, and to determine if claimed SGRP costs are reasonable.
2013-05-13		I.12-10-013.P1 Evidentiary Hearing, Phase 1, confined to events of 2012 during the outage.
2013-06-07		SCE announced permanent shutdown of SONGS.

2013-07-12		I.12-10-013.P2 Pre-hearing Conference, Phase 2
2013-08-06		I.12-10-013.P1A Evidentiary Hearing, Phase 1A on replacement power calculations.
2013-10-07		I.12-10.013.P2 Evidentiary Hearing
2013-11-19		I.12-10-013.P1/1A Proposed Decision
2013-12-23		NRC Issues "FINAL SIGNIFICANCE DETERMINATION OF WHITE FINDING AND NOTICE OF VIOLATION, NRC INSPECTION REPORT 05000361/2012009 AND 05000362/2012009"[6] stating that SCE had violated NRC regulations in the steam generator project.
2014-01-15		I.12-10-013.P1/1A PD All Party Meeting
???		I.12-10-013 Secret settlement negotiations held without informing all parties, thereby disallowing their participation.
2014-03-27		I.12-10-013 Settlement conference held. Secretly negotiated settlement revealed to the other parties with no opportunity to participate in the negotiations.
2014-03-29		I.12-10-013.P1/1A Revised Proposed Decision released
TBA		I.12-10.013.P2 Proposed Decision (not done)
TBA		I.12-10.013.P3 Pre-hearing Conference (not done)
TBA		I.12-10.013.P3 Evidentiary Hearings (not done)
TBA		I.12-10.013.P3 Proposed Decision (not done)
TBA		I.12-10.013.P4 Pre-hearing Conference (not done)
TBA		I.12-10.013.P4 Evidentiary Hearings (not done)
TBA		I.12-10.013.P4 Proposed Decision (not done)
	45.39	TOTAL OSG work (100%), 6.7% of $671M

III. Context -- Review of Precedent

The purpose of this section is to analyze recent precedents of Commission decisions regarding early closures of plants and failed projects. We found it was most convenient to cover this topic early in our comment document as multiple references to the same cases were necessary in several sections.

6 NRC ML13263A271 - "FINAL SIGNIFICANCE DETERMINATION OF WHITE FINDING AND NOTICE OF VIOLATION, NRC INSPECTION REPORT 05000361/2012009 AND 05000362/2012009" -- http://www.copswiki.org/Common/M1406

Nuclear plants are a relatively new technology, and safety concerns developed over time and as scientists and engineers began to understand many of the risk factors. Two major risk factors that began to be appreciated included both natural events, such as earthquakes, and human and design error events, such as were exhibited by the Three Mile Island accident in 1979[7]. The potential for devastating earthquakes and why they happen was just coming into focus during the period when the nuclear industry was undergoing rapid expansion.

1. Earthquake Risk Understanding Evolves

It is useful to review the development of the knowledge of earthquake risks as we review the treatment of power plants.

The great Alaskan earthquake in 1964 was one of the most important events that prompted additional attention to this risk factor. The devastation that occurred even in a sparsely populated area demonstrated the potential for enormous losses in other parts of the United States.[8]

The theory of plate tectonics was defined in a series of papers between 1965 and 1967, which revolutionized our understanding of geologic processes.[9] Scientists came to realize that the Earth is divided into about 15 plates of crust, constantly shifting as new rock forms at mid-ocean ridges and old crust dives into the Earth's interior at subduction zones in the deep sea. Consequently, in the late 1960s, a number of governmental programs were initiated to more fully understand earthquake risks and perhaps allow their prediction.

The San Fernando earthquake in 1971 reinvigorated interest in these programs and federal agencies sought increased funding. In 1973, the National Oceanographic and Atmospheric Agency (NOAA) earthquake programs were moved to the United States Geologic Survey (USGS) as a new Office of Earthquake Studies, which also brought together USGS seismologists and geologists.

The United States Congress, in 1977, enacted the National Earthquake Hazards Reduction Act (NEHRA), in recognition of the fact that earthquakes pose the greatest potential threat of any single-event natural hazard confronting the nation. This program is alive and well today under the umbrella of the Federal Emergency Management Agency (FEMA).[10]

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7 https://en.wikipedia.org/wiki/Three_Mile_Island_accident
8 http://www.geotimes.org/mar03/comment.html
9 https://en.wikipedia.org/wiki/Plate_tectonics
10 http://www.nehrp.gov/

The California Nuclear Safeguards Law was enacted in June, 1976, requiring that: (1) Within one year, the federal limits on liability for damages caused by a nuclear accident must be removed by law or by waiver for accidents in the state of California. (2) Within five years, the state legislature must find, by a two-thirds vote, that the effectiveness of reactor safety systems had been demonstrated by actual tests on "substantially similar physical systems" (presumably, large reactors) and that radioactive wastes can be stored or disposed of with no reasonable chance of eventual escape into the environment. Unless these conditions were met, new construction of nuclear power plants would be prohibited and existing plants would be derated and eventually phased out.

2. Human-Error Accident Risk Assessment Evolves

The Three Mile Island accident in 1979 underlined the possibility that accidents can happen at nuclear reactors even without natural inciting events, such as earthquakes. California enacted the Radiation Protection Act in 1979, to ensure that the health and safety of the public is protected in the event of a radiological incident at a nuclear power plant. Additionally, the program addresses federal regulatory requirements for nuclear power plant planning, training and exercises.

In public utilities, we must be cognizant that the utilities were attempting to implement new power generating technologies, such as nuclear, withing a changing regulatory landscape and evolving scientific and technical understanding. Thus, we find it reasonable that public utility operators should not be unduly penalized for respecting these advances, even if it means shutting down a power plant before it has reached its life expectancy, or abandoning projects that are no longer viable due to these regulatory restrictions and scientific knowledge advancements.

However, we must draw a line between changes that are brought on by regulatory changes or changes due to scientific understandings of risks and that of imprudent project management which could have been avoided by reasonable and prudent managers. Those are two very different things, and they should be treated differently by the Commission.

3. Treatment of Net Investment, ROI and Project Failures

Settlement proponent TURN has commented that the settlement is appropriate because there is no example of any plant that was retired early where the net investment value was not returned to the shareholder investors, albeit without any return on investment (ROI). We will show here that the cases cited by TURN differ significantly from the situation at SONGS, and that in other cases, costs and capital are withheld due to the case of lack of prudence and reasonable management.

A. Humboldt Bay 3

(See D.85-08-046, Application No. 83-09-49 (Filed September 19, 1983), CPUC 1985 Cal. PUC LEXIS 687; 18 CPUC2d 592, August 21, 1985)

On December 15, 1959, the Commission issued Decision D.59407, granting to PG&E a certificate of public convenience and necessity for Humboldt Bay Power Plant Unit No. 3 (Unit 3). Unit 3 is located near Eureka, California and is a natural circulation boiling water nuclear reactor.

Unit 3 began commercial operation in august, 1963, and operated for 13 years until 1976 when it was shut down for a planned refueling outage.

On May 21, 1976, the NRC issued an order modifying Unit 3's operating license. The NRC's order required that before Unit 3 could resume operation: (1) PG&E must complete a seismic design upgrading program and (2) PG&E must resolve specified geologic and seismic questions. PG&E never was able to meet the second requirement. Consequently, Unit 3 has not operated since 1976.

The reason the plant was unable to be restarted was due to new information about the geologic realities of the area, learned after drilling some oil wells, coupled with the new understanding of earthquake risks, as mentioned above. Thus, the shutdown of the plant was not due to imprudence or negligence on the part of PG&E, but instead due to a changing regulatory environment due to new information regarding earthquake risks. With that said, there were some costs that were ruled to be shouldered by the shareholder investors of the plant rather than the ratepayer, when those expenditures could have been avoided by more careful planning, specifically by not implementing seismic upgrades until it was clear that PG&E could ultimately secure approval from the NRC if they were implemented, these costs could have been avoided, and thus they were not covered by ratepayers.

B. PG&E Geysers 15

(See D.92-12-057 (Geysers 15), Application No. 91-11-036 on (Filed November 26, 1991), Application No. 91-08-049, Application No. 90-04-003, Investigation No. 92-02-002, Investigation No. 90-02-043 CPUC 1992 Cal. PUC LEXIS 971; 47 CPUC2d 143, December 16, 1992)

The Geyers geothermal generating facility started in 1960 when PG&E completed Unit

1, the first commercial geothermal electric unit in the Western Hemisphere, generating 11 megawatts of electricity[11]. Additional steam wells and plants were developed in subsequent years. In 1987, production peaked at The Geysers. Twenty-one power plants were in operation, with a total installed capacity of 2,043 megawatts. Over the next eight years, power generation rapidly declined as a result of pressure loss in the steam reservoir. Seeing that it was no longer feasible to generate as much steam, with some wells being abandoned, PG&E retired Unit 15 in 1989, and in 1992, retired Units 1, 2, 3 and 4, routing more steam to Unit 5/6.

Geysers operators (now including Calapine) begin cooperative studies on the use of augmented water injection to create steam, sustain reservoir pressure and maintain power generation. In 1995, Calpine, Northern California Power Agency, and Lake County Sanitation started to construct the 29-mile Southeast Geysers Effluent Pipeline, to deliver treated wastewater to recharge steam wells. Completed in 1997, it started bringing 9 million gallons a day from Lake County to The Geysers, where it is injected into the reservoir to increase steam pressure.

Reviewing the history of the Geyers geothermal facility, there was an evolution of thinking and understanding about how this resource could be managed over the long term. At its peak in 1987, it was producing over 2000 MW of power, but then saw steady decline. At first, owners probably thought the resource would have to soon be completely abandoned. However, with the addition of several pipelines providing 20 million gallons per day of treated wastewater to recharge the steam wells, this gave the facility new life. Calpine, the new operator, discovered that by operating the many wells and power plants as a coordinated whole, they could connect and optimize operations, avoid losses and outages, resulting in a stable output of about 725 MW, and growing.

The decision to permanently shut down Geysers 15 power plant had nothing to do with any notion of imprudency by the owner, PG&E, but rather on the fact that it became

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11 http://www.geysers.com/history.aspx

apparent that without providing new water to the wells, steam pressure would be inadequate to run turbines and thereby generate electricity.

The main point of contention in the review of this closure is whether the Geysers 15 should be considered part of the larger concept of the Geysers steamfields or if it should be considered as a separate power plant asset. In hindsight, it is clear that as operators learned more about the need for water to recharge the wells and the benefits of operating the steamfields as a coordinated whole rather than as distinct plants, viewing the plant as a distinct shutdown was probably not as valid as viewing it as part of a coordinated whole. Despite this consideration, the Commission ruled to the maximum extent as reasonably consistent with the facts in the favor of ratepayers, and refused to allow any ROI on the asset, although it did allow full return of net asset value of the plant. It is important also to underline that there was no hint of imprudency in this case whatsoever. These were all reasonable decisions when viewed in context of what was known at the time.

C. Other Plants Abandoned Due to Regulatory Change

Without going into each one at such length, we can list the following similar cases of plants that were abandoned due to regulatory change, and thus the investment value was recaptured for investors with no ROI.

1. **SDG&E Encina 1, Silvergate and LNG facilities** - The Commission denied any return on capital for several SDG&E-owned facilities (Encina 1, Silvergate and Station B power plants) removed from service because they were no longer needed after the commissioning of the Southwest Powerlink transmission line.[12] The Commission also denied any return on capital at several retired LNG facilities in the same rate case.[13]

2. **Hill Street Water Facility** - The Hill Street water facility also cited as Commission decision precedent by SCE. The facility could have been improved to eliminate the existing

12 D.85-12-108, 1985 Cal. PUC LEXIS 1112, *57.

13 D.85-12-108, 1985 Cal. PUC LEXIS 1112, *64. (This paragraph extracted from TURN opening brief on Phase 2).

contaminants and add fluoridation. However, the cost/benefit analysis weighed toward getting water from the larger adjacent water district, which had recently absorbed the operator of the Hill Street water facility, Golden State Water Company.[14] Thus, there was no decision by Golden State that instigated the closure, no bad decision to install new pumps, for example, that were faulty and thus the closure. "Conclusion of Law 1. It is reasonable to allow Golden State the undepreciated investment balance for Hill Street without a return on equity because the investment is no longer used and useful."[15]

There is one additional important point from this decision we can learn, and that is the definition of an "abandoned plant." This term has been used to apply to discontinuing a project that never begins commercial operation. In this case, however, it is used for a plant that once operated, but is closed before it reached its normal life expectancy, in this case due to expensive changes that were required to bring it up to compliance with regulations. For this reason, it is also appropriate to use this terminology for SONGS.

> After determining Hill Street cannot provide drinkable water1 (FOF 1 and 3), and must therefore be abandoned, D.10-06-031 found that, of the various replacement options, the preferred option is Golden State's agreement to acquire excess capacity available from Contra Costa.[16]

D. Closure of Mohave Generating Station in 2005

Mohave Power Station (known also as Mohave Generating Station, or MOGS)[17] was a 1,580-megawatt coal-fired power plant located in Laughlin, Nevada, first activated in 1971. Southern California Edison was the majority owner of the plant (56%) and was its operator. The plant is currently shut down and in the process of being dismantled. Mohave was the only power plant in the United States that used coal delivered by coal-slurry pipeline, i.e. coal mixed with water.

In 1998, a group of environmental advocacy organizations sued the plant's owners, alleging that its emissions of sulfur dioxide and particulate matter were in violation of the Clean Air Act. The plant was identified as a likely major cause of visibility impairment in Grand Canyon National Park by the

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14 D.11-09-017, "DECISION On The Ratemaking Treatment For The Abandoned Hill Street Water Treatment Facility And The Agreement With The Contra Costa Water District To Acquire Replacement Water To Serve The Bay Point Service Area"

15 D.11-09-017 p12

16 D.11-09-017 p3

17 D.12-11-051 "DECISION ON TEST YEAR 2012 GENERAL RATE CASE FOR SOUTHERN CALIFORNIA EDISON COMPANY" November 29, 2012, pages 652-653

U.S. Environmental Protection Agency (EPA).

The plant's owners settled the lawsuit and entered into a consent decree which required the plant to reduce SO_2 emissions no later than 2005[18]. In addition, the Hopi and Navajo signed an agreement preventing the use of water from the local aquifer to make up slurry. Subsequently, the owners estimated that additional emissions controls would cost more than $1 billion and elected to close the plant on December 31, 2005.

Thus, for the actual shutdown of the plant, there was no hint of imprudent decision making or management, as the shutdown was prompted by a change in the regulatory requirements of the Clean Air Act. In this case, the Commission allowed the net investment value to be returned to investors but refused to allow any ROI on net investment or on decommissioning costs.

E. Mohave Generating Station 1985 Accident

What is perhaps more interesting about this plant was the accident of 1985. A weld in a high-pressure 30 inch diameter steam pipe ruptured, blasting steam through a six foot by 20 foot breech, hotter than 1,000 degrees Fahrenheit into an employee lunch room and the plant's control room. As a result, six people were killed and ten other people were seriously injured. The steam caused extensive damage to the control room, as well as other portions of the plant.

In the Commission's review of this accident[19], there was ample evidence that SCE acted unreasonably and imprudently by

1. Using 1955 standards for the thickness of the pipes instead of the more recent and available 1967 standards (which required thicker steel to be used in the pipes);
2. Operating the plant consistently at higher pressures and temperatures than was specified as safe for the pipes;
3. Knowing about a pipe weld failure at the Sabine Power Plant, with identical design, and yet taking no actions;

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18 Consent Decree, 1999. Grand Canyon Trust, Inc., and Sierra Club, Inc., and National Parks and Conservation Association Inc., vs. Southern California Edison, Salt River Project Agricultural Improvement and Power District, Nevada Power Company, and Los Angeles Department of Water and Power. United States District Court, District of Nevada Judicial District, case no. CV-S-98-00305-LDG (RJJ).

19 D.94-03-048 "Investigation on the Commission's Own Motion of the Maintenance and Operating Practices, Safety Standards and the Reasonableness of Costs Incurred From the Mohave Coal Plant Accident." SCE (U 338-E), Investigation No. 86-04-002, Filed April 2, 1986

4. Destroying records of steam pressure and temperature after only three years despite knowing that this was a concern (as numerous corrective measures were tried);
5. Despite recognition of the dangers of high temperature operation and ongoing problems with reheat temperatures, not undertaking a broader inspection of the reheat system for either unit, nor taking other steps to assess the potential for creep damage; and
6. Prior to the accident, experiencing an unusually large number of failures in other types of welds located in the same piping system and yet taking no steps to institute additional inspection procedures.

The Commission ruled that: 1) Costs stemming from the 1985 hot reheat pipe rupture in Unit 2 of the Mohave generating station were unreasonable and not to be included in rates, and 2) unreasonable costs resulting from the accident were disallowed, including those costs in excess of what the company would have incurred, had Edison followed a reasonable reheat pipe inspection program and taken the necessary steps to correct weld and metal fatigue problems, including necessary power purchases while the plant was shut down for repairs.

The accident of 1985 was a disappointment in the performance of SCE and frankly, also points to inadequate oversight by the Commission which largely relied upon SCE to determine inspection regimens and to continue operation of the plant when it was well known that the pressure and temperatures in pipes in the region where the failure occurred exceeded specified maximums. But the accident did not force the plant to close permanently as SCE was able to repair the failure and continue operation.

Most importantly, the Commission found that in a case when the actions of the SCE were deemed unreasonable and imprudent, all costs stemming from the accident were not included in rates, including only those costs that would have been incurred had Edison followed appropriate and reasonable programs to inspect and correct any potential failures. Since the plant was not shut down as a result, we do not have a direct comparison to the case at SONGS. However, it seems reasonable that given the blatant disregard for safe operating methodologies by SCE at MOGS, if the plant had been damaged such that it could no longer be operated, the Commission would have likely ruled that even the remaining net investment in the plant would be sacrificed, as that would have been a "cost stemming from the rupture."

F. Helms Pumped Storage Project

The Helms case is an important comparison to the SONGS case, because it includes a failed engineering project and the utility sued their contractors and suppliers.

The Helms Pumped Storage Plant is located 50 mi (80 km) east of Fresno, California in the Sierra Nevada Mountain Range's Sierra National Forest. It is a power station that uses Helms Creek and the pumped-storage hydroelectric method to generate electricity. After being planned in the early 1970s, construction on the plant began in June 1977 and commercial operations began on 30 June 1984. It has an installed capacity of 1,212 MW and is owned by PG&E.

This project was largely successful but there was a "Lost Canyon Crossing" which was initially a failure and resulted in litigation with the subcontractor, somewhat similar to the failure of the SGRP at SONGS, and litigation with MHI. However, the two cases differ substantially since the Helms Pumped Storage project was largely successful except for the Lost Canyon crossing, which had to be reconstructed for $240 million, versus SONGS, where the entirety of the plant had to be abandoned due to the failure of the SGRP.

The section of Decision No. D.85-08-102[20] by the CPUC on the "Lost Canyon Crossing", is quoted below to allow us to elucidate two important aspects (underlining added):

> D. Lost Canyon Expenditures
>
> As Staff points out in its brief, there are an additional $240 million in capital expenditures related to the reconstruction of the Lost Canyon pipe crossing which are not a part of this application. These expenditures are the subject of pending litigation between PG&E and the crossing fabricator, U.S. Steel Corporation[21]. The contentions between the parties to that litigation concern the question of which party bears responsibility for the failure of the crossing during start-up testing. U.S. Steel contends that PG&E's contractor (a) failed to provide a safe and otherwise adequate jobsite, (b) damaged pipe sections and (c) failed to properly inspect the completed work. U.S. Steel also contends that PG&E failed to properly test, prepare and compact the foundation site for the crossing, and improperly designed the foundation to withstand the loads placed upon it during operation of the plant or to accommodate surface settlement. PG&E contends that the materials provided and work performed by U.S. Steel were defective and that the proximate cause of the pipe crossing failure was the negligence of U.S. Steel.

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20 D.85-08-102, (Helms) Application No. 82-04-12 (Filed April 6, 1982; amended April 26, 1983), OII No. 82-01-01 (Filed January 5, 1982), 1985 Cal. PUC LEXIS 781, *; 18 CPUC2d 700

21 United States Steel Corp. v. PG&E, et al., Civil No. CV-F-83-382 REC, Eastern District of California.

> Under these circumstances, we would only note that <u>PG&E should not look to ratepayers in the first instance to bear any portion of the Lost Canyon reconstruction costs. If any of these costs are not recouped by PG&E from either its contractor or U.S. Steel, PG&E will bear a heavy burden of proof in any subsequent application related to such costs to establish that ratepayers are not being required to indemnify PG&E for losses arising from its own negligence or the negligence of its contractor or project subcontractors. Ratepayers are not responsible for bearing the consequences of negligence.</u>

We also would like to focus on this following section of this same section.

> Further, we note that ratepayers lost the considerable capacity benefits which Helms adds to PG&E's resources. Should PG&E file any application to recoup Lost Canyon-related expenditures, we intend to consider an offset to revenues to reflect the <u>lost or deferred capacity benefits resulting from the delay of commercial operations at Helms</u>.

There are two important points of precedent related to the SONGS SGRP case. First, they clearly point out that the entirety of the Lost Canyon crossing reconstruction costs are not the responsibility of ratepayers, "PG&E should not look to ratepayers... to bear any portion of the Lost Canyon reconstruction costs" and then "PG&E will bear a heavy burden of proof in any subsequent application related to such costs to establish that ratepayers are not being required to indemnify PG&E for losses arising from its own negligence or the negligence of its contractor or project subcontractors. Ratepayers are not responsible for bearing the consequences of negligence."

Thus, it was expected that PG&E would come up with the $240 million in reconstruction of the Lost Canyon crossing either through litigation with its contractors or from investors. This is like lost money, and there is no ROI on this amount.

Secondly, the Commission makes it clear that the losses of the failure of the Lost Canyon crossing failure were not only the direct costs of the reconstruction, but also the "lost or deferred capacity benefits resulting from the delay of commercial operations at Helms."

When comparing this with the SONGS outage due to the failure of the new steam generators, we must ask what is the value of the "lost or deferred capacity benefits" which are the consequence of the shutdown. The entire SONGS plant was lost, and as a result, SCE and SDG&E have proposed several other projects to "fill in the gap" left by the absence of this plant, in terms of "peaker" plants, additional transmission line resources, energy storage, energy efficiency, etc. that are now needed to provide reliable power to the region (See D.14-03-004)[22].

In the Helms case, the precedent is that "ratepayers are not responsible for negligence" and the utility was to be subjected to the "heavy burden of proof" to collect from ratepayers anything for the losses, including "lost or deferred capacity benefits." This same standard should be applied to the SONGS case, including a value on the "lost or deferred capacity benefits," as the entire of the plant was forced to be abandoned as a result.

Had the SGRP not been attempted, we would also be in the position of needing many of the improvements to the grid and power system outlined in D.14-03-004, but in that case, the plant would be shut down in a systematic manner rather than as an emergency, and instead of wasting resources fixing up a doomed nuclear plant, the utilities could have instead invested in those appropriate improvement. The one-time-only and emergency improvements that were deemed necessary are costs eventually passed along to the ratepayer which would not have been required if SCE had not pushed for the SGRP at all. Thus, these costs are truly "lost or deferred capacity" as a result of the imprudent decisionmaking by SCE and the resulting abandonment of SONGS in an emergency fashion.

Before we move on from this case, it is important to touch on two more points.

First, in *Helms,* the Commission commented on whether in reasonableness reviews, prudence or imprudence is presumed:

> In Application 82-02-40, et al., Southern California Edison Co.'s application for a rate base offset for San Onofre Nuclear Generating Station Units 2 and 3 (SONGS 2 & 3), our Staff filed a motion to establish a procedural schedule specifying the utilities' "fundamental obligation" to demonstrate the basis for rate increases related to the ownership costs of SONGS 2 & 3. The utilities responded by claiming that their rate requests were entitled to a "presumption of prudence" and that other parties bore the burden of establishing imprudence-related rate base disallowances or revenue exclusions. In supporting the Staff, we rejected the notion of a presumption of prudence and held firm to our prior precedents on the issue. See Decision [*28] D.85-06-112, CPUC , slip opinion at 4 (1985).
>
> In the instant case, these usual rules were not followed. PG&E essentially relied upon a presumption of prudence. It is apparent from the record that, beginning with the commencement of the OII, Staff believed it was the party obligated to bear the greatest burdens with respect to a reasonableness showing. It is equally

22 D.14-03-004 "Decision Authorizing Long-Term Procurement For Local Capacity Requirements Due To Permanent Retirement Of The San Onofre Nuclear Generations Stations" March 13, 2014 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K008/89008104.PDF

> apparent that, having assumed the affirmative burden to establish PG&E's imprudence, Staff was overwhelmed by the task. The Consultants' report and findings hardly comport with traditional reasonableness reviews. Rather than focusing upon key events or managerial decisions related to specific construction activities which resulted in the incurring of otherwise avoidable (and disallowable) costs, the Consultants largely tried to establish the aura that the project was poorly or marginally managed. And, freed from the burdens of affirmatively proving prudence, PG&E was able to concentrate virtually its entire showing on the allegations of the Consultants in an effort to disprove imprudence.
>
> In retrospect, we find that, by issuing the OII and then by permitting Staff to suffer the greatest evidentiary burdens, we have unintentionally handicapped our review of the reasonableness of the Helms capital expenditures.[23]

Furthermore, regarding the "Lost Canyon Crossing." The Commission was quite clear that seeking any funds to cover this failure would result in a reasonableness review, with the "heavy burden of proof" borne by the utility:

> Under these circumstances, we would only note that PG&E should not look to ratepayers in the first instance to bear any portion of the Lost Canyon reconstruction costs. If any of these costs are not recouped by PG&E from either its contractor or U.S. Steel, PG&E will bear a <u>heavy burden of proof</u> in any subsequent application related to such costs to establish that ratepayers are not being required to indemnify PG&E for losses arising from its own negligence or the negligence of its contractor or project subcontractors.[24]

Therefore, it is quite clear that precedent is that if SCE chooses to avoid Phase 3 by entering into a settlement that stipulates that it will not be completed, the presumption by the Commission is <u>imprudence.</u> SCE is offered the opportunity to support their decisions in the project, and they are electing to avoid that process and instead settle, then if there is any question which relies on prudence verses imprudence, then imprudence is the clearly the presumption, based on Commission precedent.

4. Summary of Relevant Precedents

1. We do not know of any precedent where an engineering project failed, and that failure caused

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23 1985 Cal. PUC LEXIS 781, *; 18 CPUC2d 700 "Application of PACIFIC GAS AND ELECTRIC COMPANY for authority to institute an adjustment procedure for Unit Nos. 1 through 3 at the Helms Pumped Storage Project and to adjust its rates in accordance therewith; Investigation on the Commission's own motion into the construction of the Helms Pumped Storage Project of Pacific Gas and Electric Company D.85-08-102, Application No. 82-04-12 (Filed April 6, 1982; amended April 26, 1983), OII No. I.82-01-01 (Filed January 5, 1982) California Public Utilities Commission" Page 10

24 *Ibid.* Page 15

the entire plant to be abandoned, and the plant was so big that its absence may lead to quick fixes that would not have been required in a more carefully planned shutdown. Therefore, the case at SONGS is unprecedented and it will not be possible to turn to prior precedent to guide the decision without additional considerations.

2. In those cases where the plant was abandoned due to a change in the regulatory environment, most did return the net investment in the plant to shareholders with no ROI. (*Humbolt, Geysers 15, Hill Street Water, SDG&E Encina 1, Silvergate and LNG facilities)*

3. In reasonableness reviews, the presumption is imprudence, and the utility bears the "heavy burden of proof" that they operated prudently.

4. For portions of engineering projects that fail, none of the reconstruction costs should come from the ratepayer and the utility is required to litigate with their contractors before coming to the Commission. And then, the utility would be subject to a reasonableness review where imprudence is the presumption, and they and their contractor would be subject to not just reconstruction costs, but also other outage losses. (This from *Helms.*)

5. If the failure causes a temporary emergency shutdown of the plant (as in the *Mohave* 1985 accident) then the utility is responsible for all costs related to the failure except those costs that would have been the case had the utility operated to prudently such that the failure was avoided, including replacement power costs.

IV. PRUDENT OR IMPRUDENT

Based on Commission precedent, when plants are shut down due to prudent decisionmaking, then the Commission returns the net asset value of the plant (after depreciation) to the investor shareholders of the utility, whereas in cases when a project failed due to imprudent decisionmaking or management, then the utility has to deal with it on their own, i.e. "should not look to ratepayers ... to bear any portion of the ... costs."[25] There is no example (that we have seen) where a project fails and this results in the unexpected early shutdown of the entire plant, so San Onofre is unique in this regard.

1. Presumption is imprudence; utility bears burden of proof of prudence

Thus a great deal hinges on this point. The goal of Phase 3 of the SONGS OII was to determine

25 Helms.

exactly whether SCE acted imprudently or not. Without that proceeding, the presumption of the Commission is that the utility was imprudent, at least to determine which way the hinge swings. SCE has elected to avoid the opportunity to show reasonable and prudent decisionmaking, and so the assumption of imprudence remains.

Footnote 3 of the April 3, 2014 Proposed Settlement reads:

> The Commission's decisions in D.05-12-040 and D.06-11-026 directed the Utilities to file applications for the inclusion of SGRP costs permanently in rates upon completion of the project. Accordingly, SCE filed A.13-03-005 on March 15, 2013, seeking Commission approval to include the recorded capital costs of the SGRP permanently in rates. Likewise, on March 18, 2013, SDG&E filed A.13-03-014, seeking Commission approval to include SDG&E's share of recorded capital costs of the SGRP permanently in rates. Both applications have been consolidated with this OII.

The decision approving the SGRP had an automatic trigger for reasonableness review of the project should it exceed a specified limit. In Decision D.05-12-040 the CPUC said:

> Order #5: If the SGRP cost exceeds $680 million, or the Commission later finds that it has reason to believe the costs may be unreasonable regardless of the amount, the entire SGRP cost shall be subject to a reasonableness review.[26]

We would hope that although not explicitly stated, the entire cost would also be subject to a reasonableness review if the project never was completed, or if they suddenly failed due to fluid elastic instability. There is an assumption here that the steam generators work as well as they are supposed to.

We find it interesting that an inquiry into the reasonableness of the entire SGRP is called for, since we know that they failed, and therefore we didn't get what we paid for. However, by consolidating with this OII, it becomes possible for the utility to arrange for these to be considered in a phase that is never completed, and thus thwarting the reasonableness review. If the utility had acted prudently in the entirety of the project, then we should complete the reasonableness review and they should make the case. Otherwise, the assumption of imprudency should prevail, particularly when coupled with the subsequent points below.

2. Common Law Doctrine of *res ipsa loquitur*

In the common law of negligence, the doctrine of *res ipsa loquitur* (Latin for "the thing itself speaks") states that the elements of duty of care and breach can sometimes be inferred from the very

26 D.05-12-040 Page 109, Order #5

nature of an accident or other outcome, even without direct evidence of how any defendant behaved.[27] Although modern formulations differ by jurisdiction, the common law originally stated that the accident must satisfy the necessary conditions of negligence. *Mohave* discusses this issue:

> *Res ipsa loquitur* has been applied many times to cases, like this one, involving explosions of boilers or steam pipes. Courts have explained that as devices "'do not usually explode when they are in a safe condition, and are properly managed,'" an inference [*43] of negligence on the part of those in control of the device is reasonable. *Lippert v. Pacific Sugar Corporation* 33 Cal. App. 198, 207-208 (1917) (citations omitted) (steampipe explosion); *Van Horn v. Pacific Refining* etc. Co. 27 Cal. App. 105, 109-110 (1915) (steampipe cap explosion.) SCE may not selectively apply tort law doctrines to absolve itself of responsibility. Before the professional negligence standard of care could be applied in a case such as this, SCE would be required to overcome the heavy burden of showing that *res ipsa loquitur* did not apply.

Similarly, steam generators don't usually rattle themselves apart in only a few months. Since SCE was in charge of the project to replace these, then they are responsible for the result, and imprudence can be assumed due to the common law doctrine of *res ipsa loquitur.*

3. Avoiding the License Amendment Process was Imprudent

Unfortunately, SCE avoided normal review procedures designed to avoid such mistakes and ensure plant design that is safe. In December, 2013, the Nuclear Regulatory Commission (NRC) issued a notice of violation to SCE[28] regarding the actions related to the steam generator project, in that they did not seek a license amendment when it was clear that the newly designed replacement steam generators (RSGs) were significantly different in design from the original steam generators (OSGs).

SCE said that "At SONGS, the major premise of the steam generator replacement project was that it would be implemented under the 10CFR50.59 rule, that is, without prior approval by the US Nuclear Regulatory Commission (USNRC)."[29]

It is important to compare this approach to that used at the Arizona Public Service's (ARS) Palo Verde Nuclear Generating Station (PVNGS), located 40 miles west of Phoenix. ARS completed

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27 https://en.wikipedia.org/wiki/Res_ipsa_loquitur

28 NRC ML13263A271 - "FINAL SIGNIFICANCE DETERMINATION OF WHITE FINDING AND NOTICE OF VIOLATION, NRC INSPECTION REPORT 05000361/2012009 AND 05000362/2012009" -- http://www.copswiki.org/Common/M1406

29 "Improving Like-for-like RSGs" -- *Nuclear Engineering International (2012-01) Boguslaw Olech, SCE* -- http://www.copswiki.org/Common/M1252

replacing four steam generators at PVNGS[30] in 2007, a plant which is substantially similar to SONGS, in that it uses Pressurized Water Reactors (PWRs) of Combustion Engineering design with four steam generators, just like SONGS. The ARS project had no design mistakes like those made by SCE[31]. The big difference? ARS did not seek to avoid NRC approval using 10CFR50.59 and instead went through the license amendment process, including review by the NRC and members of the public. By choosing to avoid NRC approval, SCE acted imprudently and against the public interest. Sure, the license amendment process may have added two years to the schedule, and there may have been additional issues that may have scuttled the project completely. But what is better, completing a project that fails, or failing to start a project that would otherwise fail?

We don't know if following NRC rules and going through the License Amendment process would have resulted in avoiding the failure of the steam generators, but it certainly may have. And by avoiding that scrutiny, SCE essentially took on the full responsibility for the fact that the changes to the RSGs were not excessive, and it met the "form, fit and function" requirements of 10CFR50.59. By avoiding the review process, this places even more liability on SCE's shoulders. If they had gone through the process, they could say, "Look, we went through the entire process and this was carefully reviewed by the NRC and the public. No one caught this, and so we acted prudently, because we could not have done any more to make sure it was a good design." Instead, they have to say, "We did it all, and it is our (and our subcontractor's) fault."

SCE was imprudent to circumvent NRC review and the License Amendment process, including public scrutiny of their plans.

4. SCE knew about the problems long ago

If that is not enough, it seems that SCE knew about the problems with the steam generators long before they were installed. From Friends of the Earth:

> The just-released Mitsubishi Heavy Industries report on the San Onofre steam generators conclusively reveals that, <u>as far back as 2005-2006, the joint Southern California Edison/Mitsubishi anti-vibration bar design team had identified worrisome problems with Edison's proposed design for the steam generators MHI was contracted to build.</u> The report confirms that Edison's contract with

30 http://www.azplanning.org/newsltr/April08Vision.pdf "STEAM GENERATOR REPLACEMENT PROJECT – ARIZONA PUBLIC SERVICE"

31 http://committeetobridgethegap.org/pdf/CBG-SanOnofreReport.pdf -- Hirsch & Shuey, "FAR OUTSIDE THE NORM: The San Onofre Nuclear Plant's Steam Generator Problems in the Context of the National Experience with Replacement Steam Generators"

> Mitsubishi specified that the new, radically redesigned replacement steam generators meet the Nuclear Regulatory Commission's "like for like" standard (10 C.F.R. §50.59) thereby hoping not to trigger a license amendment. The report further reveals that while the design team considered significant design changes that might have addressed the void fraction/steam quality problem, it was decided that the changes not be made. The specific and only reason for not making those changes cited in the report was Edison's requirement not to trigger a license amendment process by the Nuclear Regulatory Commission.
>
> The MHI report therefore reveals that <u>Edison was aware of the void fraction problem</u> -- a problem which the utility itself has said is the basis for fluid elastic instability, which in turn is what they have told the NRC is the basis for the unusual wear and damage of the steam generators. This wear and damage led to the unprecedented thinning of thousands of tubes and release of radiation from Unit 3 -- the triggering event for the closure of both reactors, now in its 14th month.[32]

Apparently, the dictum that the project should not require a License Amendment process caused SCE to turn from the prudent and reasonable course, including attempting to address the engineering problem they were aware of as early as 2005, and instead mindlessly pursue the imprudence of avoiding the NRC review procedure, and therefore not attempting to address the known vibration problems.

Why was this requirement placed on the project? Most likely because they knew that reasonable review would scuttle a bad project, and then SCE investors would not make their exceptionally high returns. Whatever this incentive is, it must be identified and eliminated. But without a sufficiently robust review of this serious engineering and management blunder, we may never make the critical correction that will allow us to avoid the same mistake in the future.

5. Conclusion: Imprudent

Without completing Phase 3, we can only conclude that SCE was imprudent in their management of the SGRP. This imprudence was at the highest levels, because the underlying decision to avoid NRC approval was imprudent, and it guided the project away from making important design changes that may have eliminated the eventual failure. This was not a rank-and-file error or a mistake in using the wrong simulation program. This mistake was probably made by Ted Craver himself, CEO of Edison International, and by all others who went passively along with these bad decisions.

One thing is for sure. The policy that investors make exorbitant returns on projects that fail

32 http://www.foe.org/news/archives/2013-03-san-onofre-quotes-and-conclusions

must stop. In fact, bad projects fraught with imprudent requirements like "no NRC review" should not provide any return on the underlying net investment. To do otherwise is very bad policy which results in these sorts of imprudent business practices. If the CPUC goes along with this, then they are complicit in the continuation of a policy that will continue to provide very bad results.

V. PROPOSED SETTLEMENT REVIEW

In this section, we will examine each of the key terms of the settlement and explain the full range of options, and propose a reasonable position for a final ruling by the Commission.

Proposed Mandatory Settlement Criteria

We suggest that the Commission establish a set of criteria for any settlement, to include the following:

A. Settlement Should Not Be Based On Future Events

The terms of any settlement before the Commission should not include the requirement that the Commission and the public wait potentially for years or decades for a resolution of future events that may affect the outcome. All elements of the settlement should be defined when the settlement is approved. For example, getting funds from a future lawsuit that SCE will run against MHI should not be part of the settlement, whereas amortizing a fixed sum is okay, because it does not rely on future events.

B. Settlement Should Incentivize Actors

To deal with any such future events, the settlement terms should incentivize those participants that can affect the outcome. For example, providing 95% of the return of salvaging operations to the ratepayer does not incentivize SCE to effectively salvage O&M inventory because they get only 5% and the ratepayer can't do salvaging.

C. Settlement Should Be Open and Verifiable By The Public

The settlement terms must be open and verifiable. No actions by the utility should be included that cannot be easily verified. For example, if we ask what SCE's estimate is for the proceeds from salvaging plant O&M inventory, and the response was that it is none of our business (which is how SCE responded, as explained below), then this cannot be our business, and it must be left out of the settlement.

The following sections are numbered according to the Proposed Settlement document for ease of review.

1. SGRP

The Proposed Settlement key terms says this about the "steam generators":

> The utilities will not recover in rates the net investment associated with the steam generators as of February 1, 2012 (§ 4.2(d)), which is the first day following the tube leak in Unit 3. (§ 4.2(d).) These amounts ($597 million for SCE and $160.4 million for SDG&E) will not be recoverable in rates.
>
> The utilities will refund any capital-related revenue requirement associated with the steam generators collected after February 1, 2012. (§ 4.2(b).) The utilities keep all capital-related revenues for the steam generators collected prior to February 1, 2012. (§ 4.2(c).)

Although we appreciate the baby-step taken by the utilities toward fairness to the ratepayer for this debacle, this is really not a balanced position because the depreciation the entire SGRP project is weighed toward the beginning of the actual estimated useful life of that investment, and it assumes that ratepayers should underwrite the period of operation from installation to January 31, 2012.

A. How useful were the RSGs?

One of the big reasons the SGRP was proposed was the fact that the OSGs were not living up to their design life of 40 years. The SGRP decision D.05-12-040 went into great detail about the fact that the OSGs operated only 30 years, and SCE did not sue Combustion Engineering (CE) like many other utilities have done and like they did when SONGS Unit 1 had similar problems, and SCE sued Westinghouse and received a substantial judgment.

> TURN says that the root cause of steam generator tube degradation is the susceptibility to a variety of degradation mechanisms of the mill-annealed Inconel-600 (Alloy 600) steel used in the tubes. It represents that, by the early 1980s, SCE was aware that Alloy 600 was susceptible to degradation due to discoveries at other CE plants, and problems with tube degradation at Unit 1. TURN states that, by the mid-1980s, steam generators that used Alloy 600 had been replaced at six domestic nuclear plants, and by 1985 SCE was on notice that Alloy 600 was not recommended for steam generators by industry experts.
>
> TURN represents that, by the 1990s, stress corrosion cracking was recognized as a serious problem at other CE plants, and SONGS began experiencing noticeable degradation in 1993 and 1995. It states that by 1996, SCE’s own analyses revealed that SONGS was unlikely to operate for even 30 years without exceeding NRC

> imposed plugging limits. For these reasons, TURN states that SCE knew or should have known that the steam generators would need replacement.
>
> TURN states that owners of other CE plants aggressively sought compensation from CE for tube degradation. TURN also states that settlements were obtained for 9 of 13 units for which suits were filed against CE. Of the remaining four units, one was shut down in part due to steam generator degradation, and two have not decided whether to replace their steam generators. As a result, TURN states that with one exception SCE is the only owner to have failed to secure compensation in the course of replacing steam generators.
>
> TURN states that a suit filed by Consumers Power Company (Consumers Power) in the mid-1970s was settled for $36 million in cash, goods and services, and cancellation of about $4 million in claims by CE. In addition, CE shared 50% of the cost of fabricating two replacement steam generators. TURN represents that a suit filed by Florida Power and Light Company (FP&L) in 1995 was settled, but the terms were not made public. TURN says that Arizona Public Service Company (APS) took aggressive action against CE in 1995 regarding the Palo Verde Nuclear Power Plant (Palo Verde), of which SCE is a minority owner, and received substantial compensation in 1996.[33]

Also, SCE testified that the design life of the steam generators was 40 years:

> TURN points out that in its 1999 recapture application, <u>SCE stated that SONGS was designed and constructed for 40 years of operation</u>.[34]

It is really inconceivable that SCE intended to replace the steam generators and then run the plant only until the expiration of the current NRC license, which expires in 2022. The expectation was clearly that the RSGs would last at least as long as the OSGs, that is 30 years, the remaining period of this license plus a twenty-year renewal. But actually, they expected that the newly designed RSGs would last the full 40 year period or longer, maybe 50 years, allowing them to finish the second 20 year license period.

The settlement proposes that the utilities keep the depreciated portion of the SGRP, including the ROI for that portion, while returning the portion collected after Jan. 31, 2012. If we go along with that logic, the appropriate amount would be the fraction of the full life of the steam generators that provided service prior to the shutdown. The steam generators were only operational for an extremely minor fraction of the estimated operational lifetime of 40 years. Unit 2 was only operational for about

33 D.05-12-040, Pages 39-40
34 D.05-12-040, Page 41 (underlining added)

18 months[35], or 3.75% of the projected operational lifetime. Unit 3 was only operational for 11 months, or 2.3% of the projected operational lifetime.

But since SCE is unwilling to undergo the Phase 3 review of the entire SGRP, that entire sum is in question, not just the portion after the failure.

We have to compare with what would have occurred had the SGRP never been pursued. In that case, <u>the plant would have probably lasted even longer than with the SGRP completed.</u> The big difference would be:

- The entire cost of the SGRP would have been saved.
- No ROI would have been paid, even on the portion prior to the shutdown.
- Other projects reliant on the extended period of operation, would have been saved. Many capital expenditures on the plant could have been avoided if the operators knew the plant would shut down. For example, significant upgrades to the control room could have been avoided if a graceful shutdown of the OSGs was pursued.
- No additional expenditures during 2012 and 2013 would have been required, in response to the emergency shutdown.
- No emergency-mode projects would have been necessary to compensate for the sudden shutdown of such a large resource, such as installing new peaker plants, synchronous condensers, etc.
- Nuclear fuel contracts could have been more carefully planned so there would be no excess fuel at the plant or "in the pipeline", and hopefully no contract cancellation charges or losses for reselling the fuel.

The utilities argue that they should be allowed to retain all amounts collected from ratepayers prior to Feb 1, 2012, including depreciation of the SGRP investment and the associated ROI, because the steam generators were working fine up to that point. We would agree with this only if there was some "net benefit" to the SGRP as a whole. However, there was no net benefit, because the OSGs were removed prior to reaching their ultimate plugging limit. In fact, <u>the benefit was negative</u>, because the

35 Unit 2 was undergoing routine fuel rod replacement in January 2012, so it was not generating electricity when vibration caused the Unit 3 shutdown, but the routine maintenance being undertaken at the time was a planned outage, and therefore is counted toward the operational lifetime for that Unit.

OSGs probably would have lasted longer than the date of the failure of the RSGs.

From D.05-12-040, Finding of facts:

> 50. If the SGRP is not performed, it appears that Unit 3, and likely Unit 2, will continue in operation beyond 2010.[36]
>
> 62. The most recent DEI forecasts indicate a 32% probability of Unit 2 reaching the plugging limit by RFO 17 in July 2011, and a 70% probability of reaching the plugging limit by RFO 18 in April 2013. These forecasts also indicate a 46% probability of Unit 3 reaching the plugging limit by RFO 19 in January 2016. This means that without the SGRP, there is approximately a 50% probability that Unit 2 will operate until mid-2012, and that Unit 3 will operate until the beginning of 2016. [37]

From PD of Phase 1 of this proceeding:

> The steam generators in U2 were replaced and put online in January 2010; U3 steam generators were replaced and put online in January 2011. In reliance on the Commission's decision approving the Steam Generator Replacement Project (SGRP), both Utilities began to recover a portion of the originally approved costs in 2011.[38]

B. Split Shutdown Should have been preferred

We don't really know when either of the two units would have failed. Contrary to the opinion of SCE regarding the financial viability of running only one of the two units[39] (the so-called "split-shutdown scenario"), PG&E has found just the opposite in their plans for the eventual shutdown of the Diablo Canyon Nuclear Power Plant. At the recent Nuclear Decommissioning Cost Triennial Proceeding, PG&E witnesses Loren Sharp and Geoff Griffiths testified as follows[40]

> BY ALJ DARLING: Q Okay. I said before the break I have a few questions for these witnesses to make sure I understand the testimony. The first question has to do with the assumption of the decommissioning both of the units sequentially at Diablo. Was consideration given to decommissioning them both at the same time rather than having one operate for an additional year? I'm wondering about the cost impacts of that.

36 D.05-12-040 - Page 83
37 D.05-12-040 - Page 84 (underlining added)
38 I.12-10-013 et al. ALJ/MD2/KD1/jt2/sk6 PROPOSED DECISION (Rev. 1), page 6
39 D.05-12-040 - Page 36 "SCE states that if the SGRP is not performed, it would be more cost-effective to shut both units down when one of them reaches the plugging limit than to keep the remaining unit running."
40 A.12-12-013 Nuclear Decommissioning Triennial Proceeding, Transcript pages 1023-1025, underlining added.

> WITNESS SHARP: A So, the reason why you would operate one plant longer than the other is because they were licensed in sequence. So they both don't cease operations at the same time.
>
> Q I understand that. But I'm asking a more practical question about -- because we've talked about in relation to SONGS units. There are some economies that may arise when you're decommissioning both units at the same time. I'm not sure if there's been any kind of consideration of that option.
>
> A I think in general, there will be, as Geoff mentioned earlier, this is basically the high-level conceptual plan. Certainly as you were to go into the efforts like SONGS would be doing now to actually decide how you're actually going to execute it, there would be areas where you try to make sure you took economies of scale and perhaps did some items at the same time. On the other side, there will be times and places when you might be able to do better with a small workforce going from one area to another. So it depends on the topic and scope when you get to decommissioning which one might be more effective. But they would make those plans near the decommissioning.
>
> Q So Mr. Griffiths, if you have two units at the same site where there's a license ending, terminating within a year, what do you -- is there a customary practice that you follow or do different utilities use different models?
>
> WITNESS GRIFFITHS: A In our estimating logic, the delay of about a year or year-and-a-half is almost the perfect situation. If you have two units shutdown simultaneously, your dilemma is it puts the schedule, all things being equal, you'd be cutting up the reactor vessels at the same time. So by having about a year-and-a-half offset between shutdowns, you can get the experience on the first unit, do the work then, move the equipment, and the personnel to the second unit. So, actually the <u>Diablo Canyon shutdown spread of about a year and a half is almost the ideal spread relative to at the same time</u> or even sometimes seven years apart. It's actually a favorable circumstance, I believe.

Had SCE followed the more conservative approach advocated by SDG&E to allow the steam generators to be replaced as they reached their plugging limit, in hindsight, it is clear that the Unit 2 OSG would have been removed and replaced in about mid-2012, and the problems with the unit identified prior to installation of the Unit 3 RSGs. At that point, the decision probably would have been to allow the plant to gracefully close, rather than go through a complete redesign of the steam generators and eventual replacement of Unit 3 with a better design.

Thus we see now that the concern over split shutdown was really a bogus argument posited by SCE only as additional rationale to support approval of the project, and even SDG&E suggested fabricating the RSGs and not replacing them until the others had reached their plugging limit, rather than rushing the job, and now PG&E says it is better to do it sequentially.

We see now that rushing to swap out the RSGs was imprudent timing, regardless of whether the new steam generators operated for their full service life.

Strictly speaking, not only should the utilities not be compensated for any of the failed and imprudent SGRP, but they should also pay a penalty for removing the plant from service prior to the natural end of life caused by the OSGs reaching their plugging limit, due to their imprudent and nonconservative plans to replace both at the same time.

C. Rebate to ratepayers for imprudent SGRP

The bottom line is that SCE should return to ratepayers a refund of $45.39 million, as disclosed in the Background section of this document (this amount subject to check) for the SGRP itself. This is the amount paid to ratepayers prior to the Jan 31, 2012 emergency shutdown for the failed steam generators.

In addition, all amounts paid to SCE starting on Feb 1, 2012, should be returned to ratepayers.

D. Penalty to SCE for imprudent emergency shutdown

The Commission may find it is appropriate to impose a penalty for taking the plant off-line about 3-years early (that is, the average of the time the two OSGs would have lasted in the case that no SGRP was attempted), and the concomitant costs, including those to fill in the any gaps in power during the subsequent 3 years, i.e. through 2015, because the plant was removed from service unexpectedly due to imprudent failure of the SGRP. Fortunately, we have had relatively cool weather in the last couple of years, so the impact was not as great as it may have been otherwise.

CDSO is grateful that the plant is shut down. We believe, however, that appropriate disposition of the true costs in this case will prompt other plant owners to opt for an early, prudent shutdown, rather than pushing their luck with an old plant, undergoing an emergency shutdown, and then trying to quickly compensate the fact that a huge power source is suddenly unavailable.

Because SCE has elected not to take the opportunity to explain how their execution of the SGRP was prudent, and therefore the Commission must presume imprudence, the Commission may wish to penalize SCE even further than having to write off most of the SONGS plant. It may be appropriate to total up all the emergency-mode changes that had to occur due to the unplanned and unexpected shutdown. It is very important that plant operators opt to shut the plant down prudently and systematically (and thus likely a bit early) rather than wait for an emergency to force a shutdown. Strong actions against SCE are warranted to set the precedent that such failures of management will not be tolerated.

2. Base Plant

The proposed settlement defines the "base plant" as essentially all assets not including the steam generators after Feb 1, 2012, and it proposes that the net investment value of the plant be returned to corporate shareholders with a minimal (but greater than zero) ROI, of about $17 million.[41]

A. Unique case that goes beyond existing precedent

Based on our review of Commission precedent, this case is unique and not directly comparable to prior cases brought to our attention by TURN and SCE, as well as other cases we reviewed. <u>In no case did an imprudent project result in plant abandonment</u>, as is the case at SONGS. Thus, <u>this case is "worse" than any case before it</u>.

There many cases where prudent abandonment results in a return of net investment value with no ROI, and in other cases where an imprudent failure of a portion of the project (*Helms*, the Lost Canyon Crossing) or imprudent operation resulting in an emergency shutdown (*Mohave* in the 1985 accident) resulted in absolutely no willingness of the Commission to compensate the utility for the failure. The failure had to be fixed and the utility had to deal with all the issues with the contractors and suppliers.

Even though the utility was not willing to participate in the proceeding to show that their handling of the project was prudent (since the proposed settlement avoids Phase 3), the Proposed Settlement acts like this case is not even as bad as <u>prudent abandonment</u>, which is net investment return with no ROI. Instead, the Proposed Settlement proposes a rate of return of 2.95% over ten years, resulting in a ROI of $17 million.

From the outset, that is $17 million too much. But in this case, it is not fair to ratepayers to have them pay for an imprudent project that causes the complete shutdown and loss of an asset.

B. Remaining Value of the Base Plant

The base plant does have residual value, in terms of the NWO, comprising the spent fuel pools and Independent Spent Fuel Storage Installation (ISFSI, i.e. the dry cask storage area), and related

41 April 3, 2014 Settlement Agreement, Appendix A.

security, cooling and administrative infrastructure. From our calculations and estimates using three different methods, we providing this analysis[42]:

> **42. NWO portion of the plant**
> The portion of the plant that continues to operate as the NWO has been estimated using a square-footage and the 28-systems methods, and the two methods agree. Furthermore, this fraction also accurately estimates the future staffing levels. These methods are presented above. This percentage fraction will be utilized here to estimate the basis value and net asset value of the plant used for the NWO.

(a) Total Net Basis value (undepreciated)	$4562M
(b) Fraction of the plant	7.5%
(c) NWO (cost basis value, nominal$)	$ 342M
(d) Net Asset Value after depreciation (24.2% of basis[43])	$ 83M

The value of the NWO will continue for many years to come as the fuel is cooled in the spent fuel pools and gradually transferred to the ISFSI (dry cask area). Eventually, we hope the spent fuel will be transported to an area with lower population density, earthquake and tsunami risks.

Although customarily depreciated to account for useful life of assets and to allow investors to recapture their investment, the residual value of the NWO is far greater than the net asset value as calculated using the depreciation formula above. There is no free market to set the market value of this asset. However, the NWO is very valuable as part of the decommissioning project.

Other than the NWO, the only remaining value of the plant is what can be obtained by aggressively salvaging assets.

C. Transfer NWO to Decommissioning Activity

SONGS has set aside approximately $3.9 billion in nuclear decommissioning trust funds, which can be accessed for decommissioning activities. Clearly, the NWO is such an activity. We propose as a component of the settlement agreement, that the NWO be transferred (i.e. sold) to the decommissioning activity for the full cost basis value of approximately $342 million, plus traditional ROI on the undepreciated value of $83 million, adding about another $8 million. Also, we add to that the value of NWO-related CWIP, which we estimate to be $69 million. These numbers must be resolved and

42 From CDSO Phase 2 Opening Brief, paragraph 42. http://www.copswiki.org/Common/M1390

43 From I.12-10-013 CDSO Phase 2 Opening Brief, paragraph 38.: "38. Current Depreciation. According to SCE-36 Table IV-5, the "Total" line states that the accumulated depreciation of the plant is $3,878 out of $5,119 leaving $1,240 as the net investment value. Thus the remaining undepreciated fraction of the plant is 1240/5119 = 24.2%. This fraction will be applied to basis values to determine the net asset values of portions of the plant described below, since it is the practice to depreciate the plant as a whole."

checked, but for the sake of this comment, we will round this to $420 million.

3. CWIP - Construction Work in Progress

The April 3, 2014 Proposed Settlement distinguishes between CWIP associated with projects that have been, or will be, completed at some point after February 1, 2012 (“Completed CWIP”) and CWIP associated with projects that will not enter service at any time after February 1, 2012 (“Canceled CWIP.”) As of December 31, 2013, SCE’s share of Canceled CWIP was estimated at $153 million, while its share of Completed CWIP was estimated at $302 million.

These project are largely to extend the life of the plant based on the notion that the SGRP would be successful and extend the life of the plant for another 40 years. We advocate a position similar to that asserted by ORA, although our proposal is a bit more concise. We advocate that CWIP should be separated into NWO related CWIP and non-NWO related CWIP. NWO CWIP will be credited to the cost basis of the NWO and be used to calculate the value of the NWO so it can be transferred to the Decommissioning operation. Non-NWO CWIP assets should be aggressively salvaged by SCE and retain 100% of the proceeds of the salvage operation. All other amounts are written off with the net asset value of the plant.

According to our analysis in our I.12-10-013 Phase 2 Opening Brief[44], we estimated the NWO-related CWIP at $69 million out of a total of $230 million. These numbers need to be checked under the same derivation philosophy. This $69 million is added to the value of the NWO (see the part 2 above).

The remaining CWIP should be agressively salvaged by SCE to retain proceeds generated by that activity 100%.

4. Materials and Supplies (“M&S”) Inventory

The settlement agreement has proposed that M&S assets in the plant should be salvaged and the proceeds from the salvaging operation split between ratepayers and investors 95% to 5%.

It is our opinion that this split does not properly incentivize SCE to aggressively the M&S inventory, and it may turn into a grand "give away" to friends and neighbors. Instead, we propose that the utility be allowed to retain 100% of the proceeds from the salvaging operations, and thus SCE will definitely have an interest in making as much as possible from that activity.

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44 I.12-10-013 CDSO Phase 2 Opening Brief

Furthermore, we asked SCE to disclose what the expected return was from the salvaging operation, and they were unwilling to respond, essentially saying it was none of our business. From Data Request CDSO-SCE-03 Q4:

> **Q4. Is there any estimate of the return from salvaging assets at the plant, nuclear fuel, etc?**
>
> **Response to Question 04:**
> SCE objects to this request on the ground that the word “return” is vague and ambiguous in this context. To the extent you are asking whether SCE has an estimate of the expected proceeds from selling nuclear fuel or materials and supplies at SONGS, SCE objects to this request in its entirety on the grounds that any such estimate would be confidential, proprietary, and/or protected by the attorney-client privilege or the work product doctrine.

This underlines our point that this entire operation should be dealt by by SCE and they can keep 100% of the proceeds, since it is so "confidential, proprietary, and/or protected by the attorney-client privilege or the work product doctrine." It is not reasonable for a settlement to include a provision where the ratepayer is expecting a return (i.e. proceeds), without a willingness to explain what that is. This provision violates one of our proposed settlements criteria, i.e. that it must be open and verifiable.

5. Nuclear Fuel Inventory

According to the April 3, 2014 Proposed Settlement, the net book value of nuclear fuel investments was $593 million as of December 31, 2013.

With respect to the portion of this investment that was associated with fuel that SCE loaded into the core of Unit 2 in February, 2012 ($121 million), CDSO recommends that the Commission disallow any return on this investment nor any ROI, because SCE should not have loaded that fuel into the core, as this occurred AFTER the emergency shutdown and AFTER the initial results were in regarding extensive tube wear indications in Unit 2.

6. Replacement Power

The SONGS OII proceeding included several days of testimony in Phase 1A regarding replacement power. Although CDSO did not send a representative to participate in the evidentiary hearing due to costs of doing so, we did listen in to the proceeding. If the plant net investment is returned plus (low) ROI, it is highly inappropriate to also pay for power purchased to fill in at that time. On the other hand, if the Commission accepts our recommendation that the net investment value of the base plant not be returned to investors (not including the value of the NWO, which is returned at full cost basis plus ROI), it is appropriate to pay for the market rates of replacement power.

The April 3, 2014 Proposed Settlement defines replacement power as follows:

> From the start of the outage through June 6, 2013, SCE incurred outage-related market power costs (including foregone sales, but excluding planned outage periods) of approximately $615 million.

The "costs" of power purchased during the outage, and the fictitious costs of "foregone sales" are simply removed from the settlement loss column. However, we must insist that "foregone sales" cannot be included in any balancing account in an attempt to have the ratepayer compensate the utility for those costs, which were totally fictitious and meaningful only if the shutdown had been short in duration.

The "Key Terms of the Settlement" disclosed: $389M (SCE) and $128.2M (SDG&E) for a total of $517.2M. This amount will need to be checked as it does not match the $615M later disclosed in the Proposed Settlement. For the time being, we will use the figure of $517M until this is resolved.

7. Base O&M ("Operations and Maintenance")

Base O&M should be treated essentially using the same approach as CWIP, that is, separating in to NWO-related and nonNWO-related. This will likely wind up with a result simlar to what ORA suggested in Phase 1:

> ORA argued in Phase 1 that O&M costs that were not security- and safety-related be removed from rates—without explicitly adopting SCE's cost estimates, it estimated a disallowance of about $192 million ($283 million in 2012 base O&M costs minus $91.5 million classified as security- and safety-related).

Although we are open to further refinements of these numbers, we will accept this for purposes of this comment. We will hopefully be able to refine this suggestion using additional data requests of SCE.

8. SGIR O&M

In our proposal, we do not separate the O&M further in to Steam Generator Inspection and Repair, as we believe that this falls into the nonNWO-related category, per the approach described above.

9. Third Party Recoveries

The Proposed Settlement includes a very complex section to allow sharing of a potential return from legal proceedings, including their insurance carrier NEIL and their steam generator vendor, Mitsubishi Heavy Industries (MHI). The sharing of these proceeds first includes paying for all work to process the claims, then includes multiple tiers with a sliding scale of participation.

It is very poor policy to include provisions in a settlement regarding a possible future return from legal proceedings that were never any business of the Commission to begin with. The Commission was not able to approve, review, or control the contractors used by SCE in their execution of the SGRP. And, looking to the precedents of *Helms* and *Mohave*, it is clear that normally, the Commission does not get into the business of sharing in the proceeds of litigation.

In this, the proposed settlement violates one of the constraints we hope the Commission will impose, so as to avoid having to deal with this pesky settlement even decades in the future. Once the settlement is done, there should be no need to review anything ongoingly. Honestly, if the Commission approves this settlement the way it stands, we will know once and for all why the budget of the Commission is growing without bound. With settlements like this that need constant oversight and review, there is no wonder the Commission finds it has too much work to do. It is imperative that these provisions in the settlement be removed. Leaving them in is unprecedented, a ton of work, and does not incentivize SCE to pursue its litigation without any oversight or review by the public or the Commission.

Under the assumption that there is zero return of the net investment from ratepayers for the remaining plant, and zero ROI as well, CDSO takes the position that 100% of the return from the litigation with MHI and all insurance proceeds should go to the utility owners, SCE and SDG&E, and zero participation by ratepayers, as ratepayers are then isolated from the continuing imprudent management of their business.

From Data Request CDSO-SCE-03 Q1-3[45]:

Q1. What is the amount expected from the NEIL insurance to utilities?

45 In these quotations, the boilerplate text "SCE objects to this request on the ground that the request is vague and ambiguous. SCE further objects to this request to the extent it seeks information that is confidential, proprietary, and/or protected by the attorney-client privilege or the work product doctrine. Subject to and without waiving the foregoing objections, SCE responds as follows:" was not included for sake of brevity.

SCE RESPONSE
SCE has placed NEIL on notice of claims under a property damage policy and an outage policy. The NEIL policies have a number of exclusions and limitations that NEIL may assert reduce or eliminate coverage, and SCE may choose to challenge NEIL's application of any such exclusions and limitations. The estimated total claims under the outage policy through December 31, 2013, are approximately $320 million (SCE share). SCE has not yet submitted a proof of loss under the property damage policy.

Q2. What is the amount of "damages" or similar monies being sought by utilities from MHI?

SCE RESPONSE
In its request for arbitration with MHI, SCE alleged contract and tort claims and seeks at least $4 billion in damages on behalf of itself and in its capacity as Operating Agent for SONGS. SDG&E is also pursuing claims against MHI.

Q3. What is the minimum amount MHI must pay per contract?

SCE RESPONSE
There is no "minimum amount MHI must pay per contract." In its response to SCE's request for arbitration, MHI has denied all liability. To date, MHI has paid SCE $45 million in steam generator repair costs, but MHI reserved its right to challenge this charge. MHI's liability under the purchase agreement is limited to $138 million. However, limitations in the contract are subject to applicable exceptions both in the contract and under law. SCE has advised MHI that it believes one or more of such exceptions apply and MHI's liability is not limited to $138 million, and MHI has advised SCE that it disagrees.

From the NEIL insurance policy returned to ORA in one of their data requests, we see that the limit of liability is $490M for each Unit, a total of $980M for the entire plant.

Certainly, we don't want the settlement to get into the middle of this litigation. But it looks like SCE is expecting a from NEIL, between $320M and $980M and from MHI, $138M to $4 billion, or about $458 million up to nearly $5 billion.

The way the April 3, 2014 Proposed Settlement is currently structured, the utilities expect the ratepayer to make them whole (less the SGRP after Feb. 2012), and if they can get anything from MHI and NEIL, then it is split. I'm sure the attorney firms that are contractors with SCE love this arrangement because it allows them to operate with almost unlimited budget and litigate almost forever, with almost no downside. Instead, under our proposal, the actors are incentivized to complete their litigation quickly, and for as little as possible.

VI. Should SCE be "babied"?

Some may be of the opinion that it is bad policy to require that SCE "take the hit" due to their imprudent management of the SONGS SGRP, and that we should "go easy on them" so they can find investment in the market, or perhaps there is worry that SCE will suffer unduly if this occurs. In this section, we will show that these concerns are unwarranted, and there is no reason whatsoever to "baby" SCE, and instead, it should be treated as any other company would be treated in the free market.

A. Failed Projects Must Be Disincentivized

SCE argues that it is good policy for investors to achieve a relatively high return on investment on plants that are no longer "used and useful" to compensate for plants that continue to operate long after investors have made their profit[46]. CDSO disagrees with this, and asserts instead that it is poor policy, since it will encourage utilities to be careless in their evaluation of projects, will promote projects that have little actual value, and will encourage similar project failures, like the SGRP that did not make it past its first inspection. Regardless of prudence, to compensate the company as if the project was fully successful flies in the face of reason.

We believe it is essential and good policy for investors to make the highest return on projects that are used and useful. Projects that are abandoned, particularly in this case, which is due to poor design of the steam generators, should provide no return. And if the project is a complete failure, as this one was, coupled with the fact that SCE does not wish to provide any evidence of prudent, there should be no return on investment, and the net investment balance should be forfeited as well. This is the case in most investment opportunities. Regardless of prudence, some investments are failures, and very frequently, this is the outcome even if the managers of the business acted prudently at every step.

In regulated utilities, it is the practice to allow the net investment to be returned if they were prudent but nonetheless had to retire the plant early. But if imprudence exists, then that rule should be abandoned and the firm penalized to the full extent possible.

B. Original Investors have already recovered the original investment in SONGS

It is important to understand that the original investment in the plant has been recovered with

46 SCE-40, Pages 3-8. Of note is this Page 7, Lines 17-18 "The Commission’s historical ratemaking treatment of retired assets is consistent with cost-of service ratemaking and is good policy."

full return as of 2002. Based on information from SCE in Data Request CDSO-SCE-02 Q2[47], the chart in Illustration 1 was generated. It is important to note that the original plant was fully depreciated as of 2001. Residual book value of the plant is due to more recent capital expenditures, which include the SGRP and other additions.

40.

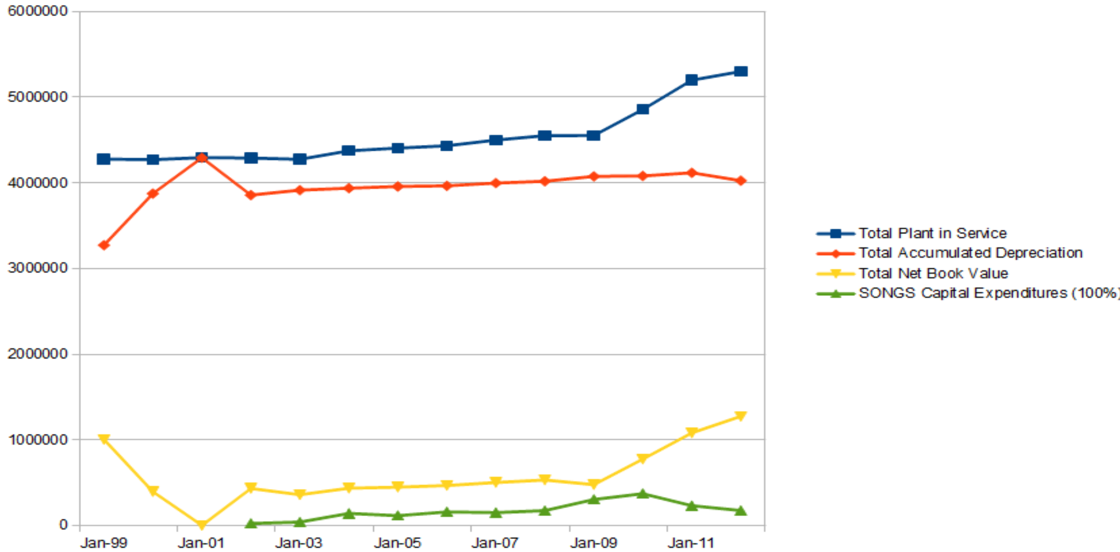

Illustration 1: Chart of SONGS Investment Value

Therefore, since original plant investors have already received the investment value and return on investment as of 2001, coupled with the fact that the SGRP was a failed project that should be disincentivized (regardless of whether SCE executed the project prudently or not,) CDSO asserts that SCE should recover $0 of the remaining abandoned plant, with 0% return on investment.

C. SCE may come out about even anyway

Although we are proposing that the ratepayer not help SCE much due to their imprudent management of the SGRP, resulting in abandonment of the plant, the company may still come out about even, compared with the April 3, 2014 Proposed Settlement, although the incentives are lined up appropriately in our proposal.

As shown in the following table, if we start with the April 3, 2014 Proposed Settlement requiring ratepayers to subsidize $3.3 billion and subtract the CDSO recommended ratepayer cost (which is primarily for replacement power at market rates or foregone sales, which are just imaginary,

47 See Appendix B of I.12-10-013.2 CDSO Phase 2 Opening Brief

and so these have already been accounted for), then also subtract the proposed sale of the NWO to the decommissioning activity, we end up with a pre-salvage and pre-3rd party recovery "loss" of $2.3 billion. Assuming SCE can salvage the plant and dig up about $300 million in salvaging proceeds, obtain coverage by their insurance carrier to the limit of liability, and get 25% of what they are asking for from MHI ($1 billion of $4 billion demand), then they are out only a measly $35 million. And since the results can vary widely, it should be left up to SCE to do as well as they can on this. They may even come out ahead, and that is okay with us, as long as we don't have to get in the middle of there litigation with MHI and their insurance company.

As you can see, this puts the onus on SCE to do as well as they can, and leaves the ratepayer out of the picture, and drastically simplifies the settlement deal.

Item Description	**Amount ($Millions)**
April 3, 2014, Proposed Settlement Ratepayer Bailout	3299
CDSO Suggested Ratepayer Cost	564
CDSO Proposed Decom. Fund Purchase of NWO including NWO-related CWIP	419
=Net Loss (pre salvaging and pre 3rd party recoveries)	2316
NEIL insurance maximum loss coverage	980
Salvaging Operation of O&M, Canceled CWIP, Fuel (CDSO Estimate)	300
MHI Suit Proceeds (CDSO Estimate)	1000
=Net Loss after Salvaging and 3rd party recoveries	35

VII. Summary of Recommended Settlement

Per the concise arguments and precedents described above, we now summarize our recommended settlement, which we feel is the only option for the Commission to take to complete this proceeding, given that the utilities do not wish to assert their right to show they were prudent in the SGRP.

Settlement Category	Recommendation	Proposed Settlement (PS)
1. Steam Generator	The entirety of the SGRP was	Pre-2/2012 payments to investors were

Replacement Project (SGRP)	imprudent and the RSGs not last as long as the OSGs would have. Investors get $0 at 0% ROI, plus refund to ratepayers the amount already paid pre-2/2012 ($45.39 million savings over PS)	at full ROI and post 1/2012 amount written off.
2. Base Plant	$420M paid from Decommissioning Trusts for NWO, including NWO-related CWIP ($69M). Rest of the plant salvaged, and then written off by investors.	$1.359G amortized over ten years at 2.95%
3. CWIP	NWO-related CWIP of $69M + AFUDC added to sale of NWO to decommissioning trusts. Remaining CWIP stops earning AFUDC on Feb 1, 2012, then salvaged with 100% of proceeds to utilities, rest written off.	Canceled CWIP no longer earns AFUDC after Feb 1, 2012. Noncanceled CWIP continues to earn AFUDC. All CWIP is then treated like the Base Plant.
4. M&S	Salvaged with 100% of proceeds to investors.	Salvaged with proceeds split 95% to ratepayers and 5% to investors.
5. Nuclear Fuel	Salvaged with 100% of proceeds to investors.	Entire cost of fuel returned to investors from ratepayers with ROI equal to commercial paper. Salvage fuel encouraged with proceeds split 95/5 in favor of ratepayers.
6. Replacement Power	This item can be eliminated from the "loss" as it is already paid by ratepayers at market prices. All notion of "forgone sales" costs are eliminated. $517M of replacement power is covered by ratepayers.	The same.
7&8. O&M	Split into NWO-related and nonNWO-related. We accept ORA's analysis stating that $92M was safety and security, related to the NWO. Ratepayers cover this amount normal return. Ratepayers save about $832M.	Split into Base O&M and Steam Generator Inspection and Repair. All O&M is covered up to Provisionally Authorized Rate Recovery amount, and no more. Total is $940M.
9. Third Party Recoveries	SCE can pursue any entity it wants to in court or by settling, and retain 100% of any proceeds. This is really their problem, and the Commission and Ratepayers should stay out of it.	Return is split between ratepayers and investors using a very complex sharing model. There is no way to control or effectively monitor this. Utilities may realize something between $458 million up to $4 billion, and ratepayers may still see almost nothing based on the tiered

		structure and the fact that costs come off the top.

SUMMARY SPREADSHEET (All figures in millions)

	PS-SCE	PS-SDGE	PS-TOTAL	CDSO POSITION Ratepayer Pays	CDSO POSITION Decom. Fund pays
1. RSG	0	0	0	-45.39	0
2. Base Plant	1115	244.5	1359.5	0	350
3. CWIP				0	69
4. M&S				0	0
5. Nuclear Fuel	394	88.3	482.3	0	0
6. Replacement Power	389	128.2	517.2	517.2	0
7&8. O&M	673	266.6	939.6	92	0
9. 3rd Parties	0	0	0	0	0
TOTAL			3298.6	563.8	419

VIII. Recommended Action by the Commission

The CDSO recommends at this juncture that the Commission take the following steps:

1. Deny approval of the Proposed Settlement of April 3, 2014.
2. Define a set of guidelines and criteria for formulation of a new proposed settlement, similar or identical to the proposed criteria we have put forward as "Proposed Mandatory Settlement Criteria" (See Section V).
3. Appoint a magistrate judge, who can carry on frank discussions with all parties.
4. Initiate additional settlement meetings with all parties so as to find a satisfactory settlement of this proceeding, which we believe will be along the lines of what we have proposed.

This approach is only fair to the various parties that were not included in the secret negotiations between TURN, ORA, and the utilities, and allows us also to include other important issues which were part of the proceeding and argued by the other parties, but completely neglected by the April 3, 2014 Proposed Settlement. Please see the CDSO initial objection and opposition to the motion to adopt the settlement.[48]

48 "The Coalition To Decommission San Onofre's Opposition To Joint Motion Of Southern California Edison Company (U 338-E), San Diego Gas & Electric Company (U 902-E), The Utility Reform Network, The Office Of Ratepayer Advocates, Friends Of The Earth, And The Coalition Of California Utility Employees For Adoption Of Settlement Agreement" (April 11, 2014) http://www.copswiki.org/Common/M1421

Appendix A – Ratepayers Reject the Settlement

In this section, we provide a number of comments and signatures from residents on petitions related to this proposed settlement. Rest assured, almost no one in the general public finds this proposed settlement to be acceptable. Attached to this document pages unnumbered) are the petition sheets gathered on this issue.

The phone numbers and email addresses have been redacted.

Dear Ray,

This is to indicate my disapproval of the CPUC settlement.

As an alternative to adopting the settlement I agree with your suggestion to negotiate better terms, or to complete the full CPUC investigation, including Phase 3, which is slated to review the reasonableness of the entire Steam Generator Replacement Project (SGRP). Completing the investigation can provide important lessons learned and influence policy to avoid similar failures in the future.

I join you in recommending that the Commission deny approval of the current settlement, set guidelines for any future settlement, including minimum criteria for provisions and provide settlement procedures to include all parties of the proceeding. And also in recommending the appointment of a magistrate judge that can hold frank discussions with both sides.

Sincerely,
Margaret Kuchnia
2309 Shamrock St.
San Diego, CA 92105
\(Resident in SDG&E Service Area)

NOTE: THE REMAINDER OF THE COMMENTS AND PETITIONS ARE INCLUDED IN THE COMPANION FILE NOTED AS APPENDIX A.